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Description

ARTICULATED DRILLSTRING ENTRY APPARATUS AND METHOD

BACKGROUND OF INVENTION

[0001] Well drilling operations are typically performed using a long assembly of threadably connected pipe sections called a drillstring. Often, the drillstring is rotated at the surface by equipment on the rig thereby rotating a drill bit attached to a distal end of the drillstring downhole. Weight, usually by adding heavy collars behind the drill bit, is added to urge the drill bit deeper as the drillstring and bit are rotated. Because subterranean drilling generates a lot of heat and cuttings as the formation below is pulverized, drilling fluid, or mud, is pumped down to the bit from the surface.

[0002] Typically, drill pipe sections are hollow and threadably engage each other so that the bores of adjacent pipe sections are hydraulically isolated from the "annulus" formed between the outer diameter of the drillstring and the inner

diameter of the wellbore (either cased or as-drilled). Drilling mud is then typically delivered to the drill bit through the bore of the drillstring where it is allowed to lubricate the drill bit through ports and return with any drilling cuttings through the annulus. Because the drill-string and wellbore are often several thousand feet in depth, a tremendous amount of pressure is required to pump the drilling mud down to the bit and back up to the surface in a complete cycle. It is not unheard of for drilling mud pressures to exceed 20,000 pounds per square inch at these depths.

[0003] Alternatively, well drilling can be accomplished through the use of a "mud motor," a device where the drilling mud flow and pressure through the drillstring is used to generate mechanical energy (through a rotor or turbine down-hole) and rotate the drill bit. Mud motor systems are frequently employed where directional and/or horizontal drilling is required, for example, in deep sea operations. In mud motor arrangements, the drill string is not rotated, but is instead "slid" into the wellbore as the bit drills deeper. In order for mud motor systems to continue to operate, a differential between bore and annulus mud pressure must be maintained else the rotor or turbine as-

sembly will not be capable of rotating the bit.

[0004] Regardless of the drilling method employed, operations of various types are performed throughout the drilling process. For instance, drill pipe sections often become stuck downhole and need to be freed. For example, directional drilling operations, wherein the drillstring is not rotated, have a higher occurrence of stuck drill pipe than traditional rotated drillstring operations. The release of stuck drill pipe is typically performed by sending a string of tools including a free-point indicator down the bore of the drillstring to determine where the pipe is stuck. Once the location determined, reverse torque is applied to the drillstring and a charge is detonated to break the threaded joints of drill pipe free at the stuck location. With the free pipe disconnected the remainder of the drillstring can be "fished" out of the wellbore. The ability to maintain the bore and annulus of the drillstring under pressure while the recovery equipment run downhole is highly desirable.

[0005] Frequently, measurements of formation density, porosity, and permeability are made before a well is drilled deeper or before a change in drilling direction is made. Often, measurements relating to directional surveying are needed to ensure the wellbore is being drilled according

to plan. Usually, these measurements and operations can be performed with a measurement while drilling assembly (MWD), whereby the measurements are be made in real-time at or proximate to the drill bit and subsequently transmitted to operators at the surface through mud-pulse or electromagnetic-wave telemetry. While MWD operations are possible much of the time, manual measurements are often desired either for verification purposes, or the measurements desired are not within the capabilities of the MWD system currently in the wellbore. Whatever the reason, it is desirable to maintain the differential in bore and annulus pressure downhole so that mud motors or other downhole equipment may continue to function while the operation is performed. Typically, the measurements are made by engaging a "tool" connected to a communications "conduit" within the bore of the drill-string and deploying the tool to the desired depth.

[0006] For the purposes of this disclosure, the term "tool" is very generic and may be applied to any device sent downhole to perform any operation. Particularly, a downhole tool can be used to describe a variety of devices and implements to perform a measurement, service, or task, including, but not limited to, pipe recovery, formation evalua-

tion, directional measurement, and workover. Furthermore, the term "conduit," while frequently thought of as a tubular member for housing electrical wires, in oilfield parlance, is used to describe anything capable of transmitting hydraulic, electrical, mechanical, or light communications from one location (surface) to another (downhole). For this reason, the term conduit, as applied with respect to the present disclosure is to include electrical or mechanical wireline, slick line, coiled tubing, fiber optic cable, and any present or future equivalents thereof.

[0007] Historically, the deployment of tools on a communications conduit to the bore of a drillstring has been accomplished through the use of entry subs. Entry subs, in their simplest form, include two inlets and a single outlet. Fluid (drilling mud) enters through one inlet under pressure, communication conduit is manipulated through the second inlet, or entry port, and both the conduit and the pressurized fluid exit through the single outlet. The development of entry subs over the years has yielded various improvements to oilfield technology, but has identified numerous needs as well.

[0008] Drillstring pipe sections are preferably mounted below the entry sub at the outlet and above the sub at the fluid inlet.

Frequently, entry subs are used in combination with top-drive assemblies to enable tools and the conduit attached thereto to be engaged within the bore of the drillstring while the drillstring is being rotated. With a rotational swivel located between the entry sub and the rotary table of the rig floor, the top-drive assembly is used to raise, lower, and hold the entry sub rotationally still from above while the rotary table rotates the drillstring below. This combination allows the drillstring to be rotated (and prevented from becoming stuck) while the tool disposed on the communication conduit is deployed into the bore of the drillstring. Because the entry sub provides a sealing engagement with respect to the conduit entering therethrough, drilling mud can be continued to be maintained at pressure while the conduit is deployed.

[0009] Formerly, entry subs were constructed as "side entry" subs, whereby the drillstring inlet and outlet were substantially coaxial and the conduit entry port was skewed at an angle to the axis of the drillstring. Examples of a side entry sub of this type can be viewed in U.S. Reissue Patent No. RE 33,150 issued to Harper Boyd on January 23, 1990 (as a reissue of U.S. Patent No. 4,681,162 issued on February 19, 1986) both hereby incorporated by reference

herein.

[0010] This arrangement required the conduit and any tool attached thereto to overcome an angle of inclination in order to pass through the tool body en route to the lower pipe section. For this reason, only the smallest and most flexible of tools (and conduits) were capable of being used with the side entry sub, severely limiting the benefits of using the device. Larger, more rigid, tools required the bottom drillstring connection to be separated (preventing the maintenance of drilling fluid bore pressure) while the tools were "made up" and inserted into the bore of the drillstring. These tools would be connected to the conduit (previously stripped through the side entry port) and run partially into the drillstring before the connection between the side entry sub and the drillstring (as well as the drilling fluid pressure) could be restored. These operations required a lengthy break in mud flow operations that could be costly in terms of rig time as well as in terms of when used, would need to be made-up below the bottom tool joint of the entry sub and would be stripped into the drillstring without being able to maintain fluid pressure.

[0011] Over time, entry subs were improved and were developed as top entry subs, whereby inlet and outlet drillstring pipe

sections are no longer co-axial. Preferably, the conduit entry port (top entry port) was located substantially coaxial with the lower drillstring outlet so that the inlet drillstring connection was skewed at an angle to the axis formed by the top entry port and the lower drillstring. Examples of a top entry sub of this type can be viewed in U.S. Patent No, 5,284, 210 issued on February 8, 1994 to Charles M. Helms and Charles W. Bleifeld hereby incorporated herein by reference. This "bend the fluid instead of bend the tools" approach was a success and resulted in adoption throughout the industry.

[0012] However, another primary function of the top entry sub (as a member of the drillstring) is to support the total weight of the complete length of the drillstring. To manipulate the drillstring up and down into the well, the top-drive assembly (or derrick crane lifting block) must be capable of lifting several thousand feet of steel drill pipe at one time. While the drilling fluid serves to buoy some of this total weight, lengthy drillstrings frequently weigh hundreds of thousands of pounds, depending on their length, diameter, and sidewall thickness. As an integral component of the drillstring when installed, the top entry sub must also be capable of supporting loads of this type.

However, much concern arose with the loading capabilities of the top entry sub because of the axial offset between the bottom drillstring connection and the top drillstring connection. This offset, while allowing conduit and tools attached thereto to be engaged straight into the drillstring without overcoming a bend angle, also could potentially induce bending moments and loads in the body of the top entry sub, if high tensile loads were applied across drillstring inlet and drillstring outlet ports.

[0013] As a result of these concerns, investigations were performed to determine the bending moments experienced across the top entry sub and within the rotary threaded connections for the drillstring components attached thereto. While the results indicate that the bending loads and moments are not a significant factor, there is still the perception by some in the industry that the loads remain a factor. Additionally, as drilling technology progresses, deeper and smaller diameter wells are being drilled everyday, particularly offshore in deep water situations. Therefore, the offset nature of the top entry sub may again become an issue in that deeper wells require longer lengths of pipe, resulting in even higher tensile loads. Furthermore, the smaller "gauge" drillstring that may be em-

ployed would require a similarly gauged top entry sub, one that may not, if produced, be capable of carrying the higher tensile loads without problems associated with bending moments. An entry sub arrangement capable of both allowing tools disposed upon a communication conduit to be engaged into the bore of a drillstring and handling extreme tensile drillstring loads would be highly desirable.

SUMMARY OF INVENTION

[0014] The deficiencies of the prior art are addressed by an apparatus located above a wellhead to allow a communications conduit to enter the drillstring. The apparatus preferably includes a main body with an upper and a lower end, wherein the lower end includes a lower connection to the drillstring and the upper end includes an entry port and an upper connection to the drillstring. The apparatus also preferably includes at least one articulated knuckle joint to allow deflection of the main body with respect to the lower connection to the drillstring. The apparatus is preferably configured to provide fluid communication from the upper connection to the drillstring and the lower connection of the drillstring. The apparatus also preferably includes a communications pathway extending

through the sub body from the entry port to the lower connection to the drillstring. The communications pathway is preferably configured to receive the communications conduit therethrough.

[0015] Alternatively, the articulating knuckle joint can be configured to allow deflection of the main body with respect to the upper connection of the drillstring. Alternatively still, the apparatus can include a second articulating joint, such that one is configured to allow deflection of the main body with respect to the lower connection of the drillstring and the other is configured to allow deflection of the main body with respect to the upper connection to the drillstring. The articulating knuckle joint(s) can be configured to allow or restrict rotation of the drillstring relative to the main body. The articulating knuckle joints can be configured to prevent bending moment loads from acting across the main body. Alternatively, the communications profile can include a receiving profile, one that may include a hardened wear-resistant material or a replaceable wear sleeve. Alternatively still, the articulated knuckle joint(s) may include a replaceable wear sleeve.

[0016] The deficiencies of the prior art can also be addressed by a method to deploy tools connected to a distal end of a

communications conduit into a drillstring by connecting an articulatable entry sub to the drillstring, wherein the entry sub provides an entry port, upper and lower connections to the drillstring, and an articulated knuckle joint. Preferably, the entry port is connected to the lower connection of the drillstring by a communications pathway. The method preferably includes articulating the entry sub so the communications pathway and the lower connection to the drillstring are substantially coaxial. The method preferably includes engaging tools through the entry port, the communications pathway, the lower connection to the drillstring, and into a portion of the drillstring located below the entry sub. The method preferably includes articulating the entry sub so the communications pathway is axially skewed from the lower connection to the drillstring.

[0017] Alternatively, the method can include axially loading the drillstring across the articulatable entry sub when the communications pathway is axially skewed from the lower connection to the drillstring. The method can also alternatively include an articulatable entry sub having a second articulated knuckle joint, wherein one joint is located at the upper connection to the drillstring and the second

joint is located at the lower connection to the drillstring. Alternatively still, the method can also include shifting the communications pathway from a coaxial to a skewed alignment with the lower connection to the drillstring by applying a tensile load to the drillstring across the articulatable entry sub.

BRIEF DESCRIPTION OF DRAWINGS

[0018] For a more detailed description of the preferred embodiments of the present invention, reference will be made to the accompanying drawings, wherein:

[0019] Figure 1 is a profile view drawing of an entry sub constructed in accordance with a preferred embodiment of the present invention in a straight position.

[0020] Figure 2 is cross-sectional profile view drawing of the entry sub of Figure 1 in an articulated position.

[0021] Figure 3 is a profile view drawing of an entry sub constructed in accordance with a second preferred embodiment of the present invention.

[0022] Figure 4 is a cross-sectional profile view drawing of the entry sub of Figure 3.

DETAILED DESCRIPTION

[0023] Referring initially to Figure 1, a profile-view drawing of an

entry sub system 10 having two articulated knuckle joints 30, 32 is shown. Entry sub system 10 includes an entry sub body 12 having an upper end 14 and a lower end 16. Sub body 12 may be constructed as a tubular body or any other structurally sound configuration. An upper section of pipe 18 extends up from knuckle joint 30 at upper end 14 and a lower section of pipe 20 extends from knuckle joint 32 at lower end 16. Pipe sections 18 and 20 each include rotary threaded drillstring connections 22, and 14 respectively. Connections 22 and 24 are commonly referred to in the art as "tool joints," in that they allow for the connection of additional oilfield tools or drillstring components thereto. Connections 22, 24 can be of any rotary threaded tool joint connections as one skilled in the oilfield arts would have available, but are preferably standard American Petroleum Institute (API) designs. Preferably, connections 22, 24 are sized and specified so as to match corresponding tool joints of adjacent drillstring components (not shown).

[0024] Entry sub system 10 is preferably installed above a wellhead with the remainder of the drillstring (not shown) mounted below at connection 24 and above at connection 22. While installed in drillstring, entry sub system 10 al-

lows for the transfer of drillstring fluids and loads therethrough, all the while providing for the entry of tools into the drillstring through an entry port 26 (more easily viewed in sectioned Figure 2). Using sub system 10, a drilling operator is able to maintain drilling fluids in the bore of the drillstring at pressure while allowing tools inserted into the pressurized bore through entry port 26 to perform oilfield operations below. Tools inserted through port 26 will be of numerous functions and types and will typically be deployed upon the distal end of a communication conduit. Entry port 26 of sub body 12 is preferably sized and constructed so that as many tools as possible are able to pass therethrough, into pipe section 20, and further downhole. Port 26 is preferably constructed so that knuckle joint 32 can be manipulated so that the center axis of pipe section 20 is substantially coaxial to the center axis of entry port 26, thereby allowing passage of tools and communication conduit therethrough with little or no obstruction.

[0025] Referring now to Figure 2, a cross-sectional profile view of the entry sub system 10 is shown. As can now be seen more clearly, sub body 12 includes a conduit entry passage 40, a fluid inlet passage 42, and a fluid and conduit

exit passage 44. A communications conduit 5 is shown entering sub body 12 at entry port 26, extending through passage 40 until it reaches exit passage 44 where it proceeds with fluid flow from inlet passage 42 through knuckle joint 32 into pipe section 20. Preferably, a hydraulic pack off device (not shown), known to one skilled in the art, is located at a receptacle 46 at the beginning of entry passage 40 at port 26 to prevent hydraulic fluids from passages 40, 42, and 44 from escaping entry sub system 10 around conduit 5 or when conduit 5 is absent.

[0026] Optionally, a receiving profile 48 can be located within entry passage 40 along the length of sub body 10 where conduit 5 would be expected to contact and abrade the wall of passage 40. Profile 48 may be of any type and design to either prevent abrasion of passages 40 of 44 resulting from extended manipulation of conduit 5 therethrough. One example for profile 48 would include a build-up of hardened, wear-resistant, material such that life of sub body 10 is maximized. Alternatively, profile 48 can be constructed as a replaceable sleeve of hardened material that could be replaced when worn.

[0027] As conduit 5 passes through exit passage 44, knuckle joint 32 is encountered. Knuckle joints 30, and 32 are

preferably constructed as ball-and-socket joints but any flexible joint (including, but not limited to, a U-joint design) known to one skilled in the art may be employed. Knuckle joints are shown located within receptacles 50, 52 of sub body 12 and are designed to receive substantially spherical ends 54, 56 of pipe sections 18 and 20. Furthermore, knuckle joints 30, 32 may also be constructed to either restrict or allow relative rotational movement between sub body 12 and pipe sections 18, 20. By adding splines (or their mechanical equivalent) to spherical ends 54, 56, they can be prevented from rotating with respect to their receptacles 50, 52 in sub body 12.

[0028] To receive ends 54, 56, spherical sockets 58 are placed within receptacles 50 and 52. Sockets 58 may be constructed of any material known in the art, but are preferred to be manufactured of high-strength and wear-resistant materials to maximize their longevity. Furthermore, sealing methods known in the art may be easily employed to prevent fluids from passages 40, 42, and 44 from escaping through any interfaces between sockets 58 and receptacles 50, 52 or between sockets 58 and spherical ends 54, 56. Metal-to-metal seals, elastomeric seals, and fiber-reinforced polymer seals can be so employed. If

spherical end 54, 56 to sub body rotation is desired, the seals must be capable of experiencing the rotation without a loss in performance.

[0029] Following installation of socket 58 into receptacle 50, 52, spherical ends 54, 56 are engaged therein, and backup compression rings 60 are installed. Compression rings 60 may also be of any material known in the art but are also preferred to have high compressive strength and good wear resistance. Furthermore, to ease in their installation, compression rings 60 may be segmented (for instance, in halves) so the outside diameters of pipe sections 18, 20 may be larger than the internal diameters of compression rings 60. Finally, compression nuts 62 are installed behind compression rings 60 and tightened to compress knuckle joint 30, 32 together and properly seat any seals therein.

[0030] Additionally, a replaceable abrasion sleeve 64 may be installed within spherical end 56 of knuckle joint 32 to protect the material of pipe section 20 from abrasion from continued manipulation of conduit 5 therethrough. Abrasion sleeve 64 is preferably constructed of a hardened metal but may also be constructed as a relatively soft material with an applied hardness coating to increase wear resistance thereof. Finally, a hardened sleeve or hardened

coating may optionally be applied to inner diameter 66 of pipe section 20 to resist any wearing experienced thereof from conduit 5.

[0031] Referring briefly to upper knuckle joint 30, no hardened wear sleeve is shown. Instead, spherical end 54 includes a conical profile 68 that allows fluid flowing therethrough to pass more easily. Because no conduit 5 is expected to pass through knuckle joint 30, a hardened sleeve (similar to item 64) is not needed, but may, nonetheless, be used. Optionally, upper pipe section 18 can be constructed similarly to pipe section 20 below in the event that pipe section 20, or its components, becomes worn and no replacement is immediately available. If components of section 20 become worn, it can be swapped with upper section 18, allowing operations to continue while replacements are located.

[0032] Figure 2 shows entry sub system 10 experiencing a tensile load condition, one where the central axis of pipe sections 18 and 20 are substantially coaxial, in contrast to Figure 1 where entry port 26 and pipe section 20 are substantially coaxial. This condition occurs when large tensile loads (for example, when the drillstring is lifted or maintained in tension by the top-drive assembly or traveling block of

the oil derrick) are placed across sub body 12 through pipe sections 18 and 20. Knuckle joints 30, 32 are constructed to be capable of carrying significant tensile loads without hazard. In position shown in Figure 2, knuckle joints 30, 32 allow sub body 12 to be cocked to the side and thereby prevent any bending moments from building up therein. As such, the tensile forces from below are carried through knuckle 32, body 12, and up through knuckle 30 to the traveling block and or top-drive assembly coaxially without placing any drilling components in any bending conditions.

[0033] In this configuration, entry port 26 permits communication of conduit 5 and any tools attached thereto through knuckle joint 32, pipe section 20, and into the remainder of the drillstring, but the amount of clearance is diminished by the angular displacement between entry port 26 and pipe section 20. This diminished amount of clearance may prevent the largest and most inflexible tools from being able to pass through knuckle 32, exit passage 44, and entry passage 40, but many useful tools will still be able to pass. When larger clearance from entry port 26 through to lower pipe section 20 and drillstring is needed, the axial drillstring loading can be temporarily reduced

(for example, by setting slips below), thereby allowing the entry passage 40 and lower pipe section 20 to once again line up in a substantially coaxial arrangement, allowing tools and conduit to be easily engaged or removed therethrough. Once the tool is removed or inserted, the drillstring loading can be re-applied, allowing knuckle joints 30, 32 to tilt sub body 12 again. While a reduced clearance for conduit 5 and tools exists in the position shown in Figure 2, there still remains enough clearance for manipulation of the conduit in and out of the wellbore.

[0034] Furthermore, while Figures 1 and 2 depict an entry sub system 10 having two knuckle joints, 30 and 32, it should be understood by one of ordinary skill in the art that a system might be employed that uses only one knuckle joint. The single joint system (not shown) could be manufactured at a lower cost than a two joint system, and could be capable of reducing bending loads to a tolerable amount. The single knuckle system could be constructed with the knuckle at either the upper or the lower connection to the drillstring, depending on the preference of the operator.

[0035] Referring briefly to Figures 3 and 4 together, an alternate embodiment of the entry sub system 100 is shown. Entry

sub system 100 is configured to allow an existing top entry sub 112 (or in some instances, a side entry sub) without knuckle joints to be converted for knuckle joint use. Particularly, entry sub system includes an upper knuckle adapter 118 and a lower knuckle adapter 120. Upper knuckle 118 is attached to a drillstring inlet located at an upper end 114 of sub 112 while lower knuckle adapter 120 is attached to a drillstring outlet located at a lower end 116 of sub 112. Each knuckle adapter 118, 120 would likewise provide a corresponding knuckle joint 130, 132 and a subsequent connection to the drillstring 122,124. The ability to convert prior entry subs for knuckle joint use avoids scrapping potentially outdated technology (cost savings) and allows a rigsite operator to customize his or her entry sub solution according to their particular needs (customer choice).

[0036] Numerous embodiments and alternatives thereof have been disclosed. While the above disclosure includes the best mode belief in carrying out the invention as contemplated by the named inventors, not all possible alternatives have been disclosed. For that reason, the scope and limitation of the present invention is not to be restricted to the above disclosure, but is instead to be defined and

construed by the appended claims.